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PETROLEUM SCIENCE AND TECHNOLOGY
Vol. 20, Nos. 7 & 8, pp. 841–866, 2002

SCREENING CRITERIA FOR CO_2 STORAGE IN OIL RESERVOIRS

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ABSTRACT

Oil fields are likely to the first category of geologic formation where carbon dioxide (CO_2) is injected for sequestration on a large scale, if geologic sequestration proves feasible. About 1.4 BCF per day (69 300 tonnes/day) of CO_2 are currently injected for oil recovery in the U.S. Replacing this naturally occurring CO_2 with anthropogenic CO_2 would have a minor, but measurable, effect on overall CO_2 emissions. However, CO_2 is injected into only a small fraction of reservoirs and it is estimated that upwards of 80% of oil reservoirs worldwide might be suitable for CO_2 injection based upon oil recovery criteria alone. These facts combined with the generally extensive geologic characterization of oil reservoirs and the maturity of CO_2–oil recovery technology make oil reservoirs attractive first targets as CO_2 sinks. This paper lays the groundwork necessary to evaluate whether an oil reservoir might be suitable for CO_2 storage. As such, a series of criteria for injection into currently producing, depleted, or inactive reservoirs are proposed. Aspects considered include the reservoir depth, storage capacity, water and oil volumes in place, formation thickness, and permeability. Importantly, the

DOI: 10.1081/LFT-120003717 1091-6466 (Print); 1532-2459 (Online)

effect of oil production on reservoir properties, especially fault movement and induced fractures must be gauged and included in assessments. It is demonstrated that CO_2 density with depth alone is not a sufficient criterion for choosing candidate sites. It is necessary to consider also porosity and the amount of water and oil that are displaceable. The end result is a criteria table for rapid screening of candidate reservoirs.

INTRODUCTION

Sequestration of carbon dioxide (CO_2) is defined as the capture and long-term storage of this green house gas such that it is removed from the atmosphere (Reichle et al., 1999). Long-term storage refers to geologically significant periods of time and without abrupt introduction of sequestered CO_2 into the atmosphere. Sequestration options might include ocean disposal, increased production of biomass, and injection into geologic formations, such as oil reservoirs and aquifers. While not directly a mode of sequestration, improvement in energy conversion efficiency and utilization of low or non-CO_2 producing primary energy sources provide effective options for significantly reducing the mass of CO_2 emitted to the atmosphere.

First attempts at sequestration, the Sleipner West aquifer-storage project withstanding (Korbol and Kaddour, 1995), will likely be concentrated in the area of injection of anthropogenic CO_2 into sedimentary basins containing oil or gas. A variety of reasons support this conjecture. Oil and gas reservoirs, by the very fact that hydrocarbons accumulated, are known to be effective in preventing the upward migration of fluids over long periods of time. Likewise, gas injection is a widely practiced method to enhance the production of oil (Moritis, 2000). Surface and subsurface infrastructure already exists in oil and gas fields that could be adapted to CO_2 distribution and storage. Much research has been directed toward the mechanisms of CO_2 movement, and the risks associated with CO_2 injection into oil reservoirs have largely been assessed. Upon consideration of depth and oil gravity, roughly 80% of the oil reservoirs worldwide could qualify for some form of CO_2 injection (Taber et al., 1997A). The cost of CO_2 sequestration efforts would thus be offset by increased oil production and partial closing of the CO_2/fossil energy loop.

Consider other options, for instance, ocean sequestration. Oceans represent a tremendous possible sink (cf., Brewer et al., 1999), but they are held and governed by international treaties. This fact indicates that a large degree of international cooperation is required, and it is likely that substantial time is needed to develop the consensus among nations necessary to move forward. Compounding this problem, ocean circulation patterns and other physical processes are not well understood, especially with regard to climate. Time, significant research, careful risk assessment, and adjustment of public perception are required to demonstrate the efficacy and environmental compatibility of ocean sequestration.

Since the inception of CO_2 injection for enhanced oil recovery (EOR) in the 1970s, significant reservoir engineering effort has gone into reducing the volume of CO_2 required to recover a barrel of oil. The objective of combined EOR and CO_2 sequestration, however, is to increase the amount of CO_2 left behind when the reservoir is abandoned; thus, the engineering design objective is significantly different. There are three principal mechanisms by which CO_2 may be sequestered within an oil reservoir. The first is physical containment or so-called hydrodynamic trapping of CO_2 as a gas or supercritical fluid beneath a caprock (Law and Bachu, 1996). Next, CO_2 can dissolve directly into water and oil phases. This is sometimes called solubility trapping (Reichle et al., 1999). Lastly, CO_2 can react either directly or indirectly with reservoir minerals and organic matter and be converted into a solid phase (cf., Bachu et al., 1994). This process may be rather slow. Whereas the engineering objective is changed and it may be possible to exploit CO_2 retention mechanisms not generally considered during oil recovery, it follows that CO_2 sequestration in oil reservoirs is not simply a direct transfer of fossil fuel production technology as others have suggested (Stevens and Gale, 2000). Selection of appropriate sites must be undertaken with care and the question of integrity of geologic seals considered throughout the design and implementation of a geologic sequestration scheme.

The purpose of this paper is to examine, from a reservoir engineering perspective, those aspects of a particular oil reservoir that might make it an attractive sequestration target. Thus, a rational selection process is provided. Before proceeding, it is helpful to review the use of CO_2 for enhanced oil recovery (EOR). Next, reservoir characteristics are examined along with a set of heuristic rules for identifying promising sequestration prospects. In this way, we establish a conceptual model for CO_2 sequestration along with oil recovery A premise found throughout is that CO_2 sequestration should be conducted so as to maximize any incremental oil production and thereby offset the costs of CO_2 compression and transportation. Waiting until a field is depleted improves neither sequestration nor oil production (Winter and Bergman, 1993).

CO_2 FOR EOR

Roughly, 1.4 BCF per day (69 300 tonnes/day) of CO_2 are currently injected into oil reservoirs for EOR (Moritis, 2001). Most of this carbon originates from naturally occurring geologic traps. At this time, CO_2 is injected into only a small fraction of active reservoirs both in the U.S. and worldwide. There is considerable volume available in other active and depleted fields.

Screening criteria have been proposed elsewhere for selecting reservoirs where CO_2 may sustain or increase the production of oil (Taber et al., 1997A and B) and need not be reexamined here. An issue of major importance to the efficiency of CO_2-based enhanced oil recovery is miscibility of the CO_2 in the oil phase (Orr and Taber, 1984; Blunt et al., 1993 and Orr et al., 1995). Dissolved CO_2 reduces oil viscosity and causes the oil phase to swell. Both viscosity reduction and swelling improve the efficiency with which CO_2 displaces oil.

Miscibility is understood via hydrocarbon–CO_2 PVT (pressure–volume–temperature) behavior. If pressure is high enough, the partitioning of hydrocarbons into the CO_2-phase coupled to flow behavior can create mixtures that are close to the locus of critical points for the mixture. Near critical and at higher pressures, essentially 100% of the oil contacted by CO_2 can be displaced. The parameter summarizing this combination of phase behavior and flow is the minimum miscibility pressure (MMP). It signifies the pressure needed to recover 90% of the oil originally in place from a one-dimensional laboratory slim tube with the injection of 1.2 pore volumes of CO_2. Practically, MMP is the pressure necessary to assure the mutual solubility of oil and CO_2 and thereby achieve significant recovery. MMP varies with oil composition and density and generally increases as oil becomes more dense. For this reason, CO_2 injection is not usually recommended unless oil density is 900 kg/m^3 (22°API) or less and the reservoir depth exceeds 760 m (2500 ft) (Taber et al., 1997A).

Figure 1 illustrates the correlation between reservoir depth and oil density for active CO_2 injection projects in the U.S. (Moritis, 1998; Taber et al., 1997). Recall that on the API gravity scale, the density of water at standard conditions is 10°API and less dense oils have greater values of °API (McCain, 1990). As this figure demonstrates, screening values are merely suggested cutoffs. There are a number of rather shallow projects. In fact, CO_2-EOR operations are not limited to light crude as conventional screening might suggest. There are CO_2 injection projects that do not achieve the MMP for their respective oils (e.g., Issever and Topkaya, 1998 and Perri et al., 2000). Oil recovery is less with immiscible CO_2 injection as compared to miscible injection, but can be large enough to be economic.

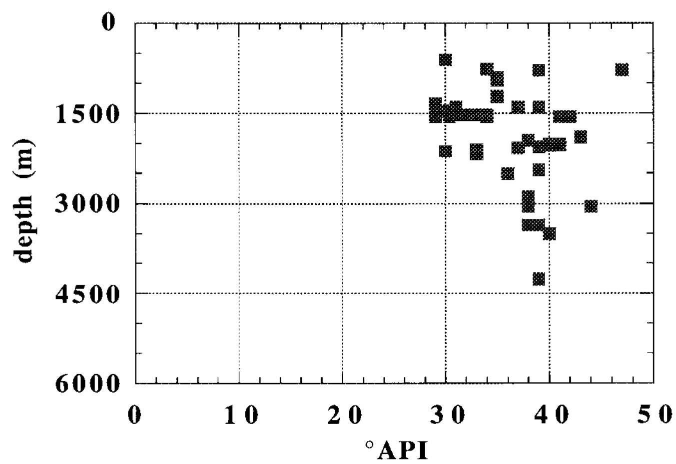

Figure 1. Correlation of depth and oil gravity for active CO_2-EOR projects in the U.S.

Recovery mechanisms remain swelling of the oil phase and viscosity reduction with CO_2 solubility in the oil phase. Hence, it is not clear that MMP will be a useful indicator of successful CO_2 sequestration projects where the primary concern is to store effectively CO_2.

In addition to oil density and reservoir depth (i.e., pressure), other reservoir characteristics of successful CO_2 injection projects include oil saturation, S_o (volume fraction of pore space occupied by oil) above 20% and effective reservoir confinement of injected CO_2. The process has found wide applicability in both sandstone and carbonate formations with a variety of thicknesses of hydrocarbon bearing zones. Because CO_2 viscosity is low compared to oil and water, and injectivity (defined later) is inversely proportional to viscosity, injection is relatively easy in all types of formations.

Within the U.S., most CO_2-EOR operations are centered in the Permian and Rocky Mountain basins (Texas, New Mexico, and Colorado). Total production is a little less than 200 000 bbl/d (3.2×10^4 m^3/d) and thus roughly 7 MCF of CO_2 (0.36 tonne) are required for every 1 barrel of oil produced (Moritis, 2000). Pipelines carry CO_2 from natural sources such as McElmo Dome, Colorado and Jackson Dome, Mississippi several hundred miles to the oilfields (Moritis, 2001). A significant fraction of the injected CO_2 remains in the reservoir, but some is produced along with the oil. Generally, this CO_2 is separated from the oil, recompressed, and injected back into the reservoir. There is less CO_2-EOR activity outside of the U.S. with notable exception in Turkey (Issever and Topkaya, 1998).

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In summary, CO_2 injection projects in oil reservoirs have focused on oil with densities between 29 and 48°API (855 to 711 kg/m^3, respectively) and reservoir depths from 760 to 3700 m (2500 to 12 000 ft) below ground surface (Taber et al., 1997A). Formation type and thickness have not been factors that affect oil-recovery performance.

RESERVOIR ENGINEERING AND GEOPHYSICAL ASPECTS

Despite years of experience with oil reservoirs, the variety of options for characterizing a reservoir, and sophisticated models of reservoir performance, they remain complicated entities that must be operated with care. There are a number of reservoir engineering and geophysical concepts from petroleum production that carry over directly to sequestration. Reservoir engineering concepts include carbon density (i.e., phase behavior), specific pore volume, fluid injectivity, reservoir/aquifer interaction, and incremental oil recovery. Next, these important ideas are explored. Further discussion of reservoir engineering topics can be found in the books by Dake (1978) and Craft and Hawkins (1991).

Reservoir Engineering Aspects

Carbon Density

A primary consideration related to sequestration capacity is the carbon density of the CO_2 stored. It might be ideal for sequestration to be carbon neutral. That is, hydrocarbon is removed from the reservoir, energy contained within the hydrocarbon is released, and the resulting CO_2 is put back into the oil or gas reservoir where the hydrocarbon originated. An example best illustrates the difference in carbon density between oil and gas reservoirs. Table 1 summarizes, typical properties of oil and gas at reservoir conditions. The carbon content upon the total mass of each molecule is also given. Note that the density of carbon within oil is much greater than it is within natural gas.

Next, properties of CO_2 are needed. The Peng–Robinson equation of state is used (Peng and Robinson, 1976 and Reid et al., 1987) along with the critical temperature, critical pressure, and accentric factor tabulated by Reid et al., (1987). As others have noted (cf., Hendricks and Blok, 1993), CO_2 density increases with depth. Figure 2 illustrates that the density of

Table 1. Typical Properties of Oil and Gas at Reservoir Conditions

Fluid	Density at Reservoir Conditions (kg/m^3)	Carbon Ratio (kg-C/kg-Total)	Carbon Density at Reservoir Conditions (kg/m^3)
Oil (C_nH_{2n+2})	800	~12/14	686
Natural gas (CH_4)	180	12/16	135
Carbon dioxide (CO_2)	600	12/44	164

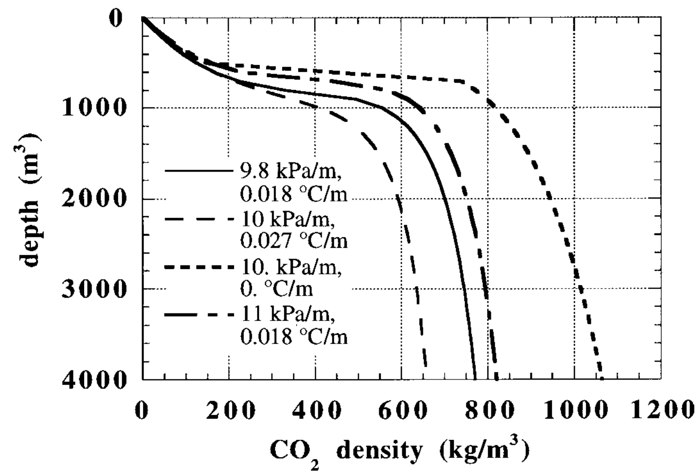


Figure 2. Density of CO_2 as a function of depth for various assumed hydrostatic and geothermal gradients.

pure CO_2 will be greatest at a given depth in a reservoir where the fluid pressure gradient is largest while the geothermal gradient is the least. All gradients used in Figure 2 are physically reasonable except the geothermal gradient of 0°C/m. The lowest hydrostatic gradient represents pure water while the larger numbers are characteristic of brines. Hydrostatic gradients are used to calculate pressure because aquifers generally overlie oil and gas reservoirs. It is the column of water and rock above the reservoir that determines reservoir pressure. Note that the geothermal gradient reduces CO_2 density significantly. In the absence of a geothermal gradient, CO_2 phase density exceeds water density at a depth of roughly 2750 m. Thus, the CO_2 would tend to migrate downward rather than upward. With the inclusion of the geothermal gradient, CO_2 does not approach water density even at depths of 4000 m.

Continuing with the example, we choose arbitrarily a depth of 1200 m, a geothermal gradient of 0.018°C/m, and a hydrostatic gradient of 9.8 kPa/m. As illustrated in Figure 2, the density of CO_2 is about 600 kg/m^3. The density of carbon within CO_2 for this case is a little more than 160 kg/m^3 (Table 1). All of the CO_2 produced from the combustion of natural gas can be stored in the original gas reservoir. On the other hand, the carbon density of CO_2 is only about one-fourth that of the oil. The choice of physical properties in this example is somewhat arbitrary. The results, however, indicate that it will be difficult to achieve carbon neutrality with CO_2 injection into oil reservoirs. The carbon density of liquid hydrocarbons is significantly greater than that of CO_2 under most conditions.

Specific Capacity

Carbon density alone is not a sufficient parameter to calculate the theoretical storage capacity of an oil reservoir. Various reservoirs will demonstrate differing capacities to sequester CO_2 depending on the void fraction or porosity of a rock, the fraction of the porosity that can be filled with CO_2, and the reservoir depth and temperature. The specific capacity or the mass of CO_2 per volume of rock is a good measure to differentiate sequestration potential among reservoirs. Let ρ be the density of CO_2 as a function of p and T, S_{or} be the residual oil saturation or the amount of oil that is physically unrecoverable, and S_{wir} be the irreducible water saturation or the amount of water that is held so tightly to the rock by capillarity that it cannot be displaced. Carbon dioxide can also dissolve in the water phase, and so, let C_s be the mass of CO_2 dissolved per unit volume of water. Then, the sequestration capacity of the rock C is expressed as

$$C = \rho(1 - S_{or} - S_{wir})\phi + S_{wir}\phi C_s \qquad (1)$$

A combination of a reservoir that is deep such that CO_2 density is large, that has sizeable porosity, and that contains a large fraction of moveable fluids leads to maximum CO_2 sequestered.

Another example helps to make ideas concrete and illustrates the need to consider the rock sequestration capacity in concert with CO_2 phase density. In the first case (a), the reservoir is roughly 760 m deep. Its temperature is 44°C and the average fluid pressure before any oil production began was 7.7 MPa. Let the reservoir be a high permeability sand such that porosity is large, say ϕ equals 0.3, and irreducible water saturation is low, say S_{wir} equals 0.15. In case (b), we assume that the reservoir is deeper but less permeable. The depth is 2200 m. Initial average fluid pressure was 22.4 MPa at discovery and temperature is 65°C. Because the reservoir is less permeable, we expect porosity to be lower (cf., Bear, 1972) and the irreducible water saturation to be larger. Set ϕ to 0.12 and S_{wir} to 0.25. For both cases (a) and (b), it is assumed that oil recovery was efficient and the residual oil saturation is low, say S_{or} equals 0.05. CO_2 solubility in water is calculated from the data shown by Koide et al. (1993). Again, CO_2 phase properties are calculated from the Peng–Robinson equation of state (Reid et al., 1987).

For sequestration, we suppose that a conservative course of action is to increase pressure to roughly the original reservoir fluid pressure. We also assume that injection is carried out in an isothermal manner so that reservoir temperature is unchanged. Because S_{or} is low, we do not consider partitioning of CO_2 into the oil phase. Any reactions leading to mineralization of CO_2 are neglected. Table 2 summarizes the parameters and results. In both cases, the CO_2 is supercritical. In case (a) the CO_2 density is 232 kg/m^3 while in case (b) it is 710 kg/m^3. Despite the approximately tripling of CO_2 density because of the increase in pressure with depth, the sequestration capacity of each case is roughly equal to 60 kg of CO_2 per m^3 of rock. The solubility of CO_2 in pore water adds roughly 5% to the specific sequestration capacity of these cases.

Of course it will be difficult to obtain a uniform distribution of CO_2 over an entire reservoir column. Gravity will tend to segregate CO_2 at the top unless density is comparable or greater than that of oil. Nevertheless, the idea of a specific storage capacity gives us a means to compare various reservoirs with respect to depth, porosity, and moveable water and oil saturation.

Table 2. Parameters and Results for Specific Capacity Example

	Case (a)	Case (b)
Depth (m)	760	2200
p (MPa)	7.7	22.4
T (°C)	44	64
ρ (kg-CO_2/m^3)	231.6	709.6
C_s (kg-CO_2/m^3)	50.4	59.4
S_{or}	0.05	0.05
S_{wir}	0.15	0.25
ϕ	0.3	0.12
C (kg-CO_2/m^3-rock)	57.9	61.4

Injectivity

Injectivity, I, is a quantitative measure of the ease with which a fluid, such as gas or water, can be placed into a geologic formation per unit thickness of the formation. It is computed as (Dake, 1978)

$$I = \frac{q}{h\Delta p} = \frac{2\pi k}{\mu \ln(r_e/r_w)} \tag{2}$$

where q is the volumetric flow rate at the bottom of the well, h is the formation thickness, Δp is the pressure drop between the reservoir and the well, k is formation permeability, μ is the injected phase viscosity, and r represents radius. The subscripts e and w refer to the equivalent drainage radius of the well and the wellbore radius, respectively. Through adjustment of r_e, the effect of reservoir geometry other than radial can be probed. Note that I is linearly proportional to permeability and inversely proportional to the viscosity of the injected phase. Injection is more difficult for viscous fluids and/or low permeability formations. However, an attractive feature of CO_2 injection is the relatively low viscosity of the CO_2 phase. At a pressure, p, and temperature, T, of 15 MPa and 47°C, respectively, CO_2 phase viscosity is only 0.077 mPa-s (Lohrenz et al., 1964) as compared to 0.68 mPa-s for water. Due to its relatively low viscosity, volumetric injection rates of CO_2 can be large in both permeable and low permeability formations. This fact has already been realized for EOR operations with CO_2. Formation permeability is not given as a criterion limiting the applicability of CO_2 injection (Taber et al., 1997A).

The question of CO_2 injectivity for sequestration has been addressed in the context of aquifers (Law and Bachu, 1996, Gupta et al., 1999). As suggested by Eq. (1), it was found that even generally low permeability formations can accept large volumes of CO_2 and that the storage rate was enhanced by regions of high permeability. Interestingly, heterogeneous, high permeability paths are generally viewed in a negative fashion for CO_2-based EOR. Efficiency of oil recovery is reduced by high permeability paths and gravity segregation that promotes incomplete reservoir sweep (Tchelepi and Orr, 1994). When the rate of CO_2 injection must be maximized, high permeability paths, or so-called "thief zones" are possibly beneficial. A zone of high permeability around a well greatly enhances the rate and cumulative injection versus time into a formation. The degree of enhancement depends on the contrast in permeability between the thief zone and the formation as well as the size of the heterogeneity (Law and Bachu, 1996).

Reservoir Flow Mechanics

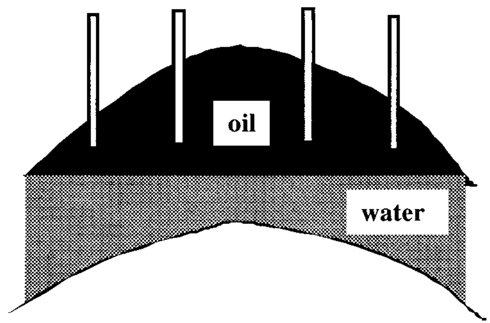
While injectivity is enhanced by the presence of thief zones, the fraction of the reservoir that can be filled with injected gas is controlled by the interplay of reservoir heterogeneity, gravity, and the efficiency that injected gas displaces any fluids in the pores. The viscosity of CO_2 is low, generally, as compared to oil and water phases. As illustrated above, the viscosity of high pressure CO_2 is, at its maximum, only a few hundreths of a centipoise (mPa-s). Fluid mobility is inversely proportional to viscosity. This implies that injection gas will be highly mobile, relative to oil and water, and find preferential flow paths. The effects of heterogeneity can be modified somewhat by gravity-induced vertical flow; however, the effect of heterogeneity is rarely negated.

Flow patterns of course must be examined for every specific system. The mobility ratio, however, is a good indicator of the degree of preferential flow that might be expected. It is simply the injected fluid mobility upon the resident fluid mobility. The larger the value of mobility ratio the more likely that preferential flow will occur. In such a case, the microscopic (i.e., pore-level) displacement efficiency may be high, but the macroscopic storage efficiency is reduced through the combination of heterogeneity, high mobility ratio, and gravity segregation. These ideas are explored more fully by Jessen et al. (2001). They examine how reservoir flow mechanics determine the rate at which CO_2 is sequestered.

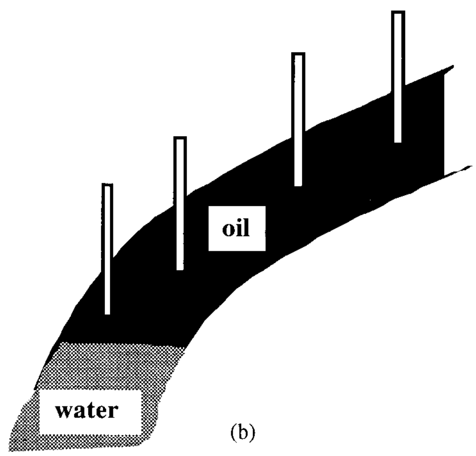
Aquifer–Reservoir Coupling

In general, oil production efforts have depleted oil reservoirs of a substantial portion of their original pressure. Pressure is reduced at production wells, and the pressure difference between the reservoir and the well used to drive fluids toward the well. In the same manner, reservoirs connected to an aquifer are sometimes invaded by water from the aquifer due to the pressure difference between the reservoir and the aquifer. This case is referred to as natural water drive or aquifer influx. Sometimes it aids oil recovery especially for low viscosity oils.

Water drive reservoirs are classified according to the thickness and orientation of the hydrocarbon bearing zone. Figure 3 illustrates bottom water drive and edgewater drive reservoir configurations. It is assumed that the water underlying the reservoir is in communication with an aquifer. In the bottom water case, the water–oil interface lies under the entire reservoir. There is a tendency for all of the wells to produce water especially if the production wells are open to flow near the water–oil contact.



(a)



(b)

Figure 3. Schematic of (a) bottom water drive and (b) edge water drive.

In the edge-water case, the oil–water interface only underlies a portion of the productive formation. Generally, wells that are low on the structure are the first to experience high water production. There are a number of analytical expressions available to estimate the rate and extent of water invasion from an aquifer (cf., vanEverdingen and Hurst, 1949; Chatas, 1953, 1966 and Dake, 1978). These same solutions could be used for water efflux during pressurization from CO_2 injection.

An oil reservoir does not necessarily have an effective water drive. Small and/or relatively low permeability aquifers might not provide substantial water movement. The aquifer might even be inactive. Such cases are referred to as closed reservoirs. They usually have lower recovery efficiency than reservoirs with active water drives. A closed reservoir might make the most attractive target for CO_2 injection, because there is no need to displace water that invaded from an aquifer (Bachu, 2000). The initial oil saturation is likely larger compared to reservoirs with water influx, and thus the potential for incremental recovery larger. In reservoirs with active bottom water, the injected CO_2 must force out the water that invaded from the aquifer. Injectivity might be lower compared to the closed reservoir case. Nevertheless, recovery from 30 to 70% of the oil in place is typical for a field indicating substantial reservoir volume that might be filled with CO_2 in reservoirs with active or inactive water drives.

Incremental Oil Recovery

Incremental recovery is a quantitative measure of the additional oil production resulting from injecting a fluid into a reservoir. For an abandoned or depleted reservoir, an important question to consider is whether the possibility of additional oil recovery warrants reopening the field to production, and if so, on what scale. Answering such a question is rather involved and requires an assessment of the volume of oil remaining in a reservoir, its distribution, the rate with which oil can be produced, future oil price, and additional surface or reservoir facilities that might need to be installed. Obviously, this is beyond our current scope although technical and economic guidelines are available elsewhere (cf., Lake, 1989; Bondor, 1993; Taber et al., 1997A and B and Green and Willhite, 1998).

There are several heuristic rules that bear mentioning in this regard. The product of average oil saturation and porosity, $S_o\phi$, is sometimes referred to as the reservoir "SoPhi". It is a measure of the oil remaining per volume of rock. Projects with $S_o\phi$ greater than about 0.05–0.07 generally warrant consideration as they are usually profitable. Obviously, the larger $S_o\phi$ the more attractive the project due to the larger amount of oil in place and the possibility of greater return. For $S_o\phi$ less than 0.05, the possible oil recovery has to be weighed carefully against costs. In this case, it might make more sense to treat the reservoir like an aquifer. Reservoir volume is filled without bringing any oil or water to the surface thereby saving costs associated with production wells and water treatment.

Another useful and easily computed reservoir quantity is the product of average permeability and the thickness of the oil-bearing zone, kh. As Eq. (2) teaches, the injection rate q is directly proportional to both of these quantities. By analogy to Eq. (2) the amount of oil that a well can deliver is also proportional to kh. In some regards, a short but permeable reservoir is similar to a tall but low permeability reservoir in terms of the volumes of fluid that can be injected or removed. Ideally, we wish to offset the cost and energy consumption of sequestration efforts. Thus, a thick ($>0\,m$) and permeable reservoir ($kh > 10^{-13}$–$10^{-12}\,m^3$) with large $S_o\phi$ is preferable.

Geophysical Aspects

The reservoir engineering aspects outlined above consider the rock matrix as static. It is equally important to consider the dynamics of faults and seals as well as formation damage. These aspects control ultimately the possible transport of CO_2 to the surface. The possibilities for monitoring CO_2 movement within an oil reservoir are also discussed below.

Seals, Faults, and Fractures

Gravity will drive supercritical and gaseous CO_2 upward until it meets a seal at the top of a geologic formation. Little is known about the long-term integrity of seals, but the existence of oil and gas reservoirs demonstrate that seals can be effective. Sealing mechanisms include pressure seals such as a sealing fault that blocks all fluid movement and capillary barriers where wetting fluid occupies low-permeability media preventing the migration of a non-wetting phase such as CO_2. Over pressurization of fluids within reservoir pore space can cause a breach of any type of barrier (cf., Finkbeiner et al., 2001). Two modes of failure appear to be prevalent: natural hydraulic fracturing and slip of a sealing fault. Leaky seals on a geologic formation may not preclude sequestration as overlying geological units can provide the integrity needed to prevent CO_2 from entering the atmosphere. Some leakage may even be desirable if it provides the opportunity for increased injectivity.

Seal failure by fracturing is relatively simple, conceptually. As fluid fills rock pore space, the pore pressure increases. If the pore pressure increases substantially, the pore pressure can become equal to the least principle total stress. The rock fractures because the compressive stress is overcome by the stress exerted by the pore fluid (Howard and Fast, 1970 and Valko and Economides, 1995). Consider, the classic reservoir failure modes leading to horizontal and vertical fractures. The weight of the earth and fluids above an oil reservoir provides compression and helps to confine fluid within the pore space of a reservoir. The sum of the force per unit area on a reservoir is frequently referred to as the overburden pressure. In a majority of sedimentary basins the overburden pressure increases linearly with a gradient of 22.6 kPa/m (Dake, 1978). The overburden pressure remains constant at any given depth and leads to the following formula

$$p_{\mathrm{ob}} = p_{\mathrm{gr}} + p_{\mathrm{f}} \tag{3}$$

where p represents pressure and the subscripts ob, gr, and f represent overburden, grain, and fluid, respectively. The overburden pressure remains constant because the weight of rock and fluid above the reservoir remains unchanged. It is possible by injection to bring the pressure of fluid within the pore space so that it equals the overburden pressure. The overburden is said to be ‘‘lifted’’ because the force exerted by the pore fluid on the rock matrix just balances the weight of the overburden. A horizontal fracture results when the pressure reaches such a level. This mode of reservoir failure is fairly rare because the distribution of stress within a formation is generally not equal in all directions. The least of the principle stresses within a hydrocarbon reservoir is usually oriented in a horizontal direction and vertical fractures are induced rather than horizontal.

The effect of faults on fluid movement is complicated. Faults are known to act as seals separating distinct geological units and to provide conduits with high permeability. Recent work on the mechanical role of fluids has shown that sealing, reservoir bounding faults can become activated and leak when pore pressure is elevated (Wiprut and Zoback, 2000 and 2002). In this particular case, the Visund field in the North Sea lost natural gas containment due to a combination of factors including an increase in compressional stress arising from tectonic forces, high pore pressure due to gas accumulation beneath a sealing fault, and a fault arrangement prone to slip. It seems that friction was overcome as the sealing fault was stressed and the fault slipped. This work appears to confirm that faults capable of slipping in the current stress environment of a reservoir are permeable to fluids, whereas those that are not capable of slippage are impermeable.

As gas injection into oil and gas fields is relatively common, systematic examination of several fields for effective containment or any evidence of gas leakage might provide insight that is applicable across the entire spectrum of geologic sequestration. In this way, it can be gauged whether pore-pressure induced leakage, by either fracturing or fault movement, is a dominant mechanism constraining the capacity of geologic traps. Until such understanding is developed, we observe that reservoirs containing sufficient accumulations of hydrocarbons to be economic generally have a pore-pressure gradient less than 17.4 kPa/m (Law and Spencer, 1998). Reservoirs that had relatively small pore-pressure gradients at discovery might be especially secure CO_2 storage sights. Likewise, this suggests a heuristic rule: injection of CO_2 should be controlled so that the pore pressure gradient does not exceed roughly 17.4 kPa/m. An even more conservative course of action is to not allow reservoir pressure to exceed greatly the initial reservoir pressure.

Formation Damage

Fracturing and fault movement are but two means by which a reservoir is damaged. Other mechanisms of formation damage include: reservoir compaction, plugging of pore space by solid particles, precipitation of minerals or components of the oil, oil emulsification, and bacterial growth (Economides et al., 1994). In general, damage leads to reduced reservoir permeability and perhaps porosity. According to Eq. (2), these types of damage might reduce injectivity; however, a reservoir's ability to retain CO_2 is probably unchanged.

Monitoring

Geophysical reservoir monitoring techniques have advanced substantially. It is now possible to image, to some extent, the movement of fluids within a reservoir. These techniques include, for instance, time-lapse seismic, cross-well seismic, so-called EM (electromagnetic) imaging, and well logging. They are based upon the idea that when a reservoir fluid is replaced with an injected fluid the geophysical properties of the reservoir change. By collecting subsequent images and subtracting these images from a base or original image, it is possible to gauge the location and rate of movement of injected fluid. For instance, seismic methods measure the velocity of compressional and shear waves. In principle, the sound wave properties of CO_2-filled rock are much different as compared to oil-filled rock (Wang and Nur, 1989). Changes in velocity and attenuation associated with CO_2 injection for enhanced oil recovery have been observed in situ with high frequency crosswell tomography (Harris et al., 1995 A and B). In a time-lapse mode, this technique can be used to infer the extent and location of injected CO_2 in an underground formation.

Further description of the application and limitation of geophysical monitoring techniques can be found in the original works of Wilt et al. (1992), Wilt et al. (1997), and Newmark et al. (1999). Resolution of all techniques likely needs to be enhanced if they are to be used to detect precisely caprock leakage, fault activation, or other modes of containment loss. At this stage, geophysical imaging offers the best combination of resolving CO_2 migration inside a formation with cost.

SURFACE FACILITIES ASPECTS

The surface facilities or production engineering aspects of CO_2 sequestration are potentially as important as reservoir engineering problems. Perhaps the largest economic question associated with geologic sequestration and the use of anthropogenic CO_2 for EOR is the cost of concentrating CO_2 in dilute waste gas streams. The topic of optimal separation is beyond the scope of this paper. However, we note that research is being directed toward membrane, cryogenic, and advanced amine processes to reduce costs and improve efficiency (cf., Stevens and Gale, 2000).

A second important economic question is the cost to build pipelines that carry CO_2, and perhaps other combustion gases, from the CO_2 source to the point where it is injected into the earth. Consider the CO_2 pipeline from the Great Plains coal gasification plant in Beulah, N.D. to the Weyburn oil field in Saskatchewan, Canada. The pipeline runs 330 km and cost roughly $122 million to build (Hancock, 1999 and OGJ, 1999). This project is a massive undertaking that will successfully combine economy of scale, the need for CO_2 to conduct EOR at Weyburn, and tax credits. Costs to build pipelines vary somewhat depending on location and land use in the area through which a pipeline passes. Table 3 summarizes average cost data. The largest diameter, highest capacity pipelines easily top $1 million per mile to construct. Proximity of a particular oil field to large sources of CO_2 would appear to favor that field for sequestration.

The additional surface facilities aspects are somewhat better treated in the literature. Thus, they are covered in less detail here. Pure CO_2 in gas, liquid, or supercritical form is not corrosive. However, contaminants found in flue gas, such as water and sulfur dioxide (SO_2), will create a

Table 3. Average Cost Data (1994) for an Onshore Pipeline in the U.S. (McAllister, 1998)

Pipe Diameter (Inches)	$/Mile
8	202 568
12	253 920
24	701 832
36	981 972
48	1 262 640

corrosive CO_2 mixture. Water reacts with CO_2 and SO_2 to form carbonic and sulfuric acid, respectively.

The tact taken for moving natural CO_2 from its source fields to oil fields in the Permian Basin has been to dehydrate the CO_2 and purify it before placing it into the pipeline. Granted, cleaning a highly concentrated CO_2 gas stream is less involved than cleaning a lower concentration stream. But this technique avoids altogether the need for stainless steel or other expensive types of pipe to move CO_2 effectively. For aquifer sequestration, it has been suggested that water content of anthropogenic CO_2 be 500 ppm or less (van der Meer, 1993). A less conservative criterion has been suggested at greater than 90% purity as guided by oil field practice (Dove et al., 1999).

Alternative means are also available to reduce corrosion. The art of inserting a polymer liner or an epoxy coating into low-grade steel pipe has advanced significantly. As long as the liner or coating is undamaged, such pipes exhibit excellent corrosion resistance (Mason, 1999). Corrosion can also be reduced by injecting a corrosion inhibitor along with the CO_2 (Perry and Green, 1984).

SUGGESTED SCREENING CRITERIA

As CO_2 sequestration in geologic media is in its infancy, we cannot rely on the characteristics of past successful projects to guide our choice of screening criteria for injection of anthropogenic CO_2 into oil reservoirs. Three broad areas of characteristics appear to be relevant: reservoir properties, oil properties, and surface-facilities properties. Each is discussed in turn. Table 4 summarizes these criteria. The central idea of Table 4 is that a majority of positive attributes could lead to a successful CO_2–oil field sequestration project.

The picture that emerges from the discussion of engineering principles above suggests that the density of CO_2 at reservoir depth and pressure needs to be considered in concert with the porosity and the volume of fluids that are displaceable. This combination of factors leads to maximum sequestration per unit volume of reservoir rock. Thus, the specific sequestration capacity C is proposed as a screening parameter. Whereas the specific sequestration capacity indicates the mass of CO_2 that might ultimately be sequesterable in a formation, it gives no indication of the rate at which CO_2 can be sequestered. The injectivity I appears to be a natural parameter in this regard; however, it is normalized by reservoir thickness. It does not differentiate among two reservoirs with equal permeability, but radically different thickness. Thus, the product of reservoir

Table 4. Screening Criteria for Anthropogenic CO_2-EOR and CO_2 Sequestration

	Positive Indicators	Cautionary Indicators
Reservoir properties		
$S_o\phi$	≥ 0.05	< 0.05 Consider filling reservoir voidage if capacity is large
kh (m^3)	$\geq 10^{-14}$–10^{-13}	$< 10^{-14}$ if kh is less, consider whether injectivity will be sufficient
Capacity (kg/m^3)	> 10	< 10
Pore pressure gradient (kPa/m)	≤ 17.4	> 17.4
Location	Divergent basin	Convergent basin
Seals	Adequate characterization of caprock, minimal formation damage	Areas prone to fault slippage
Oil properties		
ρ (°API, kg/m^3)	$> 22\,900$	< 22 Consider immiscible CO_2 EOR, fill reservior voidage if C is large
μ (mPa s)	< 5	> 5 Consider immiscible CO_2 EOR
Composition	High concentration of C_5–C_{12}, relatively few aromatics	n/a
Surface facilities		
Corrosion	CO_2 can be separated to 90% purity in a cost effective manner	H_2O and H_2S concentration above 500 ppm each
Pipelines	Anthropogenic CO_2 source is within 500 km of a CO_2 pipeline or oil field	Source to sink distance is greater than 500 km
Synergy	Preexisting oil production and surface facilities expertise	Little or no expertise in CO_2-EOR within a geographic region

permeability and thickness, kh, is a better screening parameter in this regard. Additionally, the larger the initial oil saturation at the beginning of sequestration, the more potential there is for a stream of revenue from oil sales. The combination of parameters $S_o\phi$ captures this aspect.

Next consider the characteristics of the oil within a reservoir. An implicit assumption throughout is that sequestration in oil reservoirs will be accompanied by additional production of oil. This production will offset the costs and energy consumption of sequestration. Because the most efficient production of oil by CO_2 EOR comes from miscible displacement of relatively light oils, it is suggested to follow the CO_2-EOR criteria that have already been established (Taber et al., 1997). Oil density should be greater than 22°API and viscosity should be less than about 5 cP. Similarly, the oil should be composed of a large percentage of hydrocarbons with chain lengths from 5 to 12 carbons long to promote miscibility of oil and CO_2. Also in this regard, a higher fraction of straight chain alkanes is preferable to aromatic compounds.

These first reservoir criteria reflect potential and the ease with which CO_2 might be injected. Additional reservoir criteria are needed reflecting the integrity of the caprock or reservoir seals. Proceeding with the logic that a good reservoir trap for oil and gas will also make an effective site for CO_2 storage, the initial pore pressure gradient is a good screening parameter. Thus, a pore pressure gradient of roughly 17.4 KPa/m or less is suggested. Additionally, it would seem prudent to select a reservoir where the geology, physical structure, and rock mechanics have been characterized extensively. At the very least, prior data will reduce the cost of implementing a sequestration project. Without a more or less complete understanding of caprock mechanics, avoiding convergent basins that are subject to plate convergence and subduction, and hence earthquakes, might be prudent (Bachu, 2000). Such regions might be subject to fault movement, fracturing, and the release of CO_2. Divergent basins are generally associated with more stable tectonic areas and are not prone to frequent earthquakes.

A major surface facility characteristic that would appear to dominate oil reservoir sequestration is the distance of the source of CO_2 from either an oil field or a CO_2 pipeline. The cost of very long pipelines appears to be prohibitive. The DOE has proposed that 500 km might be the maximum distance to move CO_2 from its source to a sequestration site (Reichle et al., 1999). Logical choices of reservoirs are in states that already produce a significant volume of emissions from fossil-fuel fired power plants and which contain oil fields, for example, Texas, California, Oklahoma (Winter and Bergman, 1993).

Consider that significant CO_2 emissions are generated in the Los Angeles basin from power generation, chemical, and refining industries. The LA basin itself contains numerous oil fields that might employ CO_2. This hypothetical captured CO_2 could also be sent to Kern Co. in the Southern portion of the San Joaquin Valley, California where significant oil production takes place. Pilot projects have even been conducted in

Kern Co., California to test the feasibility of using CO_2 to recover oil from very low permeability diatomaceous formations (Perri et al., 2000). Of course, for geological formations in the LA Basin or San Joaquin Valley, there needs to be some assurance of minimal hazards from fault movement. Synergy also appears to be relevant to aspects of surface facilities and CO_2 sequestration in general. Preexisting expertise with EOR and especially the installation of oilfield distribution and metering facilities for injected and produced gases might make a particular geographic area more attractive than another.

DISCUSSION AND SUMMARY

While it is not necessary that each and every criterion be met in order for a successful project, it would appear that the greater the fraction of affirmatives, the more likely that a project will succeed. As in the case of conventional EOR, a word of caution is needed: successful projects are encountered that do not meet a majority of the conventional screening criteria. This will likely be the case with oil reservoir CO_2 sequestration.

Additionally, less conventional schemes for CO_2 storage in oil reservoirs need to be investigated. For example, CO_2 could be injected into the aquifer underlying a reservoir rather than directly into the reservoir (Jessen et al., 2001). Injection into the aquifer might mobilize oil trapped in the vertical capillary transition zone between the water-filled aquifer and the oil-bearing reservoir. Injection deep into the aquifer also helps to delay or minimize cycling of gas from injectors to producers.

Numerous outstanding questions remain regarding geological CO_2 sequestration in hydrocarbon reservoirs. Importantly, the potential for long-term migration must be addressed and risks assessed. This will probably have to be undertaken for every project. Another point to be addressed is the generation of conservative estimates for CO_2 retention capacity of a reservoir in the event of leakage. Due to multiphase flow effects, some amount of oil and/or gas is disconnected from the main body of fluid during migration (Dake, 1978). These "residual" phases are not mobile. Residual phase saturations, S_{gr} in the event of immiscible CO_2 injection and S_{or} if miscible, are not characterized for all rock types and gravity induced flow. A rock type that exhibits a large S_{gr} may be preferable to assure immobilization of gas and safety.

The thermodynamic opportunity cost of performing EOR with anthropogenic CO_2 must be thought through clearly. Energy will be required for separation, transportation, and reinjection of CO_2. For a power plant, the energy required for sequestration will reduce the overall efficiency of electricity generation. Some estimates are that sequestration might reduce overall efficiency of fossil fuel fired power plants by as much as 8–11% (Bolland and Undrum, 1998). Solutions other than the capture and separation of effluent gases may be more appealing from the standpoint of efficiency and consumption of resources.

In spite of these outstanding questions, oil fields are most likely as the first targets for large scale CO_2 injection. Because CO_2 is already injected on a large scale into oil reservoirs, even if in a geographically limited area, a degree of acceptance for the practice already exists. Importantly, the permitting and reporting procedures for oil field injection of CO_2 are already in place. However, CO_2 sequestration in oil reservoirs is not a straightforward application of existing oil field technology and operating practices. The engineering design question is substantially different: the objective is to maximize the amount of CO_2 retained by the reservoir. In standard EOR, it is desired to obtain the maximum recovery with the minimum amount of injected fluid.

Here, screening criteria were proposed and discussed. Obvious factors include storage capacity, depth, injectivity, and amount of remaining oil. The density of CO_2 with depth alone is not a sufficient criterion for choosing candidate sites. It is necessary to also consider porosity and the amount of water and oil that are displaceable. Reservoirs with weak or no water influx from underlying aquifers may be the most attractive, if all other factors are the same. In this class of reservoir, significant remaining oil might be found and reservoirs may be significantly pressure depleted. Hence, incremental oil recovery and CO_2 injectivity may be large. The possible integrity of reservoir seals must also be gauged. Until the time that a more complete understanding of reservoir seals is developed, it is suggested that reservoir storage sites be chosen where the initial pore pressure gradient is less than about 17.4 kPa/m. Such reservoirs are, generally, effective hydrocarbon traps and should be secure sites for storage.

NOMENCLATURE

$^\circ$API	liquid gravity on the API scale, $^\circ\mathrm{API} = (141.5/\gamma) - 131.5$
BCF	billion standard cubic feet of gas
C	sequestration capacity per volume of rock
C_s	solubility of CO_2 in water
h	reservoir thickness
I	injectivity
k	porous medium permeability
MCF	thousand standard cubic feet of gas

p	pressure
q	volumetric flow rate
r	radius
S	phase saturation
T	temperature
ϕ	porosity
γ	specific gravity, liquid upon water density, at standard conditions
μ	viscosity
ρ	density

Subscripts and superscripts

e	equivalent drainage radius
f	fluid
gr	residual gas or grain
o	oil
ob	overburden
or	residual oil
w	well
wir	irreducible water saturation

ACKNOWLEDGMENT

Support was provided by the Assistant Secretary for Fossil Energy, Office of Coal and Power Systems, through the National Energy Technology Laboratory and the GEO-SEQ project of the Lawrence Berkeley National Laboratory.

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Received August 16, 2001
Accepted September 29, 2001

Erratta: **SCREENING CRITERIA FOR CO2 STORAGE IN OIL RESERVOIRS**
PETROLEUM SCIENCE AND TECHNOLOGY, Vol, 20, Nos. 7&8, pp. 841-866, 2002

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